LESSON TITLE: OTSG TUBE CLEANING
PROGRAM: 326-506

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1.0 TRAINING AIDS
- 1.1 LESSON MODULE #19
- 1.2 TRANSPARENCY PACKAGE #19
- 1.3 WATER SLAP VIDEO TAPE

2.0 REFERENCES
- 2.1 CHAPTER 19-B&W ADVANCED MANUAL
- 2.2 Nuclear Engineering International January 1987
  Employing a chemical method for tubesheet
  sludge removal
- 2.3 Nuclear Plant Journal Sept\Oct 1988
  Steam Generator Chemical Cleaning at
  Oconee Nuclear Station

A-17

3.0 Learning Objectives

3.1 Cover the learning objectives on page 19-1

4.0 Presentation

4.1 OTSG Review

4.1.1 As feedwater enters the generator, aspirating ports supply steam to preheat the feedwater to saturation temperature. When the feedwater reaches the lower tubesheet, it is at saturation temperature. A level is maintained in the downcomer of the OTSG.

4.1.2 The 177 ICS has a HIGH LEVEL LIMITS circuit that senses OPERATE RANGE level and compares the level with a setpoint (86.5%). This comparision is supplied to a low select unit which compares the level limits circuit with feedwater demand. If HIGH LEVEL LIMITS exist the low select unit will not allow feedwater demand to increase above the LIMITS. This circuit prevents thermal shock to the tube sheet.

4.2 OTSG Fouling Problems

4.2.1 Secondary Side Fouling- The deposition of rust on the OTSG tubes and the Tube Support plates.

4.2.2 The deposition results in an increase in flow resistance of feedwater from the downcomer to the tube area of the steam generator.

4.2.3 Additional flow resistances increases the level in the downcomer area.

4.2.4 The aspirating ports could become flooded, if level covers the ports.

4.2.5 HIGH LEVEL LIMITS occurs and plants must reduce power.

4.3 Sources of Secondary System Fouling

4.3.1 High Pressure Heaters

4.3.2 MSR tube and shell drains

4.3.3 1 and 2 are not filtered by Condensate Polishing System

4.4 Plant Problems

4.4.1 Three Mile Island - 1

4.4.1.1 Power escalation after restart

4.4.1.2 reactor trip\turbine trip shakes loose debris

4.4.1.3 Level limited during operations in 1987.

4.4.1.4 Intentional Pressure Oscillations shake loose deposits

4.4.2 Arkansas Nuclear One - 1
    4.4.2.1 First problems occur in 1978
    4.4.2.2 Piping design allows Heater Drain system to prefer "A" OTSG
    4.4.2.3 Controlled boil off attempted
4.4.3 Crystal River - 3
    4.4.3.1 Lvls steadily increasing since 1977
    4.4.3.2 Limits on plant power in 1984
    4.4.3.3 samples indicate 95% magnetite
4.4.4 Oconee 1, 2, & 3
    4.4.4.1 Same problems as other plants
    4.4.4.2 Water slap and sludge lancing attempted

4.5 Tube Cleaning Methods
4.5.1 Pressure Fluctuations
    4.5.1.1 Pressure Fluctuations induced in OTSG
    4.5.1.2 Up and down power manuvers
    4.5.1.3 turbine throttle valve position changes
    4.5.1.4 turbine bypass valve position changes
    4.5.1.5 Planned reactor trips
    4.5.1.6 Limited results
    4.5.1.7 Nureg 1231
        a.) Unnecessary plant transients
        b.) Unnecessary challenges to safety systems

Controlled Boil Off

4.5.2 Sludge Lancing
    4.5.2.1 High pressure water is used to knock rust from tubes and support plates
    4.5.2.2 80 to 600 pounds of material removed
    4.5.2.3 May be used in conjunction with other methods of tube cleaning
4.5.3 Water Slap
    4.5.3.1 High pressure nitrogen is used to cause a rapid rise in water level in the OTSG which slaps against tube support plates.
    4.5.3.2 400 to 600 lbs of rust removed
4.5.4 Chemical Cleaning
    4.5.4.1 Orignally described in B&W topical reports
    4.5.4.2 Chemicals listed on page 19-10
    4.5.4.3 3000 to 4700 pounds of rust removed

OTSG

Notes

Lesson Plan (Cont)

Transparency for objectives

3.0 Objectives

After studying this section, you should be able to:

1. State the function of the integral economizer once-through steam generator.

2. List the four heat transfer regions.

3. Describe how and why the areas associated with the four heat transfer regions change with an increase or decrease in plant load.

4. Explain why the differential temperature between the steam generator tubes and steam generator shell is critical.

4.0 Presentation

Fig. 3.4-1

4.1 Introduction

4.1.1 Function of the OTSG

Designed to remove the heat generated in the reactor vessel through the process of producing superheated steam in the secondary side or steam producing section.

4.1.2 Second generation steam generator

The integral economizer OTSG was developed to handle the higher steam generator capacities of the newer plants. The 177 plant OTSG will be discussed at the end of the lesson.

4.1.3 Classification

Vertical, straight-tube, shell and tube, counter flow heat exchanger.

Notes

Lesson Plan (Cont)

4.2 Physical Arrangement, Construction, and Flowpaths

Fig. 3.4-1

4.2.1 Primary Side

A. Consists of the upper head, primary side of the upper tube sheet, inside of the tubes, lower head, and the primary side of the lower tube sheet.

B. The heads and tube sheets are constructed of manganese-molybdenum steel with all surfaces in contact with the primary coolant clad with stainless steel, except upper and lower tube sheet faces are clad with inconel to aid in the welding of the inconel tubes.

C. Primary flowpath is into the upper head via a 38" diameter nozzle, inside the 16,016 tubes, into the lower head, and out two 32" diameter outlet nozzles.

Fig. 3.4-2

4.2.2 Tubes and Tube Support Plates

A. The tubes are 0.625" across with a wall thickness of 0.034". They are made of inconel.

B. The tube support plates are of the broached design. They are made from 1.5" thick carbon steel. Provides support but does not restrict flow. Support rods and spacers fix the plate spaces. Bypass flow is limited by seal rings and wedges.

Notes

Lesson Plan (Cont)

Fig. 3.4-1

4.2.3 Secondary Side

A. Secondary side is bounded by the shell, the outside of the tubes, and the secondary side of the tube sheets.

B. Shell is constructed of mag-moly steel.

C. Tube bundle surrounded by cylindrical shroud, which channels the flow through the tube bundle.

D. Flow path of secondary fluid:

Feedwater enters the OTSG through two nozzles in the lower shell. Flows down the annulus between the shell and the shroud, then into the tube bundle region. Flows up through the tube bundle region where the water is heated from subcooled liquid to superheated steam. At the top of the tube bundle, the upper tube sheet turns the steam flow downward into the upper annulus to the two 26" steam outlet nozzles.

4.3 Instrumentation

Fig. 3.4-6

4.3.1 Level

A. Startup Range

Two channels for each steam generator. Used to control feedwater when power is ≤ 15%. Range of indication is 0 to 80 inches. Level is measured from the bottom of the tube sheet.

B. Wide Range Level

Provided for control room indication when power is > 15% and for wet layup operations. Range of scale is 0% to 100%.

4.3.2 Shell Temperature

5 thermowells along the OTSG shell to measure temperature. Used for operator indication via plant computer. Used for tube-to-shell ΔT determinations.

Notes

Lesson Plan (Cont)

Fig. 3.4-3 & Fig. 3.4-4 & Fig. 3.4-5

4.4 OTSG Operation

4.4.1 Heat Transfer Regions

A. Subcooled Region

This region is also known as the economizer section. Feedwater enters this section as subcooled liquid and is heated to saturation. Feedwater is a minimum of 390°F at the inlet to this region. Size of this region increases with increasing load.

B. Nucleate Boiling Region

The initial boiling region of the OTSG. Tubes remain wetted in this region. High heat transfer coefficient in this region, and most of the heat is transferred in this region. The mixture is about 95 weight percent steam at the outlet of this region. The size of this region increases greatly with power.

C. Film Boiling Region

A blanket of steam forms on the tubes in this region. Takes a very short section of the tubes. Steam quality at the top of this region is 100%. The size of this region over power is relatively constant.

D. Superheat Region

In this region, the steam is heated to a minimum of 50° superheat. The size of this region decreases greatly with power.

Notes

Lesson Plan (Cont)

4.4.2 Principles of Operation

Allows operation with both a constant temperature in the primary and constant steam pressure at the turbine throttle. By changing the size of the different heat transfer areas, the amount of heat transferred from the primary to the secondary is changed. This is due to the changing of the overall heat transfer coefficient in the equation:

$$\dot{Q} = UA\Delta T$$

where

$\dot{Q}$ = heat transferred

U = coefficient of heat transfer

A = area of heat transfer

ΔT = temperature difference (T_{ave} - T_{sat})

Since the size of the subcooled region and the nucleate boiling regions increase with power, the effective UA for the OTSG increases with power because these are the regions of highest heat transfer.

4.4.3 Low Power Operations

Between 0% and 15% power, the level in the OTSG is constant at 24" (called low level limits). Therefore, to increase the heat transfer, some other term in the equation must change. The term that is changed is the ΔT. This accomplished by increasing T_{ave} with power over this 15% power band.

Notes

Lesson Plan (Cont)

Fig. 3.4-7 & Fig. 3.4-8

4.4.4 Thermal Stress Considerations

A. Excessive loading of the tubes due to too large ΔT between the shell and the tubes. Tubes are trying to expand more than the shell, therefore the tubes are under compressive stresses. Minimize these stresses by heating the shell with the steam as it exits the OTSG. During startup, pull a vacuum to the steam generator to allow boiling to occur at lower temperatures and heat up the shell. A second method is to use a recirculation system.

B. Second stress is the shell-to-lower tube sheet weld area due to cold feedwater. To minimize this, the feedwater is heated even at low powers.

Fig. A1-1 & Fig. A1-2

4.5 Other OTSG Designs

The 177 plant use a slightly different design in their OTSG. This OTSG has an external feedwater header and uses aspirating steam to preheat the incoming feedwater. Emergency feedwater enters the OTSG near the top of the tube area.

Another difference is the 3 ranges of indication (startup, operating, and full). The startup range is used for low level limits and the operating range for high level limits.

This OTSG only has three regions of heat transfer in the tube bundle area. The subcooled region is not applicable due to the heating feedwater to saturation in the annulus region by the aspirating steam. The changes in the sizes of these regions with power is however the same as in the IEOTSG.

To minimize the thermal stresses in the OTSG, a minimum feedwater temperature of approximately 165° is maintained by using main steam and/or auxiliary boiler steam to a feedwater heater. Also, to maintain the shell temperature, the method of drawing a vacuum back into the shell of the steam generator is used to minimize the shell to tube differential temperature.

3.0 OBJECTIVES

3.1 List the purposes of the RCS

3.2 Describe the arrangement of the Reactor Coolant System. List and state the purposes of the following RCS Penetrations:

3.2.1 Hot Leg

a. Pressurizer surge line

b. Decay Heat Removal suction line

c. High point vent

d. flow sensing penetration

3.2.2 Cold Leg

a. Makeup and purification letdown

b. Loop drain

c. Pressurizer spray line

d. Normal makeup

e. High pressure injection

3.3 State the Purposes of the following

3.3.1 Pressurizer

3.3.2 Code Safety Valves

3.3.3 Power operated relief valve (PORV)

3.3.4 PORV block valve

3.3.5 Pressurizer spray valve

3.3.6 Pressurizer spray block valve

3.3.7 Pressurizer heaters

3.3.8 Reactor coolant drain tank

3.3.9 Pressurizer auxiliary spray

3.4 Describe the operation of the pressurizer and pressure relief system, including methods of determining safety and relief valve leakage.

3.5 Explain the pressurizer spray driving fore and the purpose of spray bypass flow c

3.6 List the conditions that are required for natural circulation.

4.0 PRESENTATION

4.1 Introduction

4.1.1 RCS Purposes

4.1.1.1 Serves as a part of the second barrier

4.1.1.2 Transfers heat from the core during normal and emergency conditions

4.1.2 General Description

4.1.2.1 Two Heat Transport loops with each loop containing:

a. Hot Leg piping

b. OTSG

c. Cold Leg piping

d. 2 RCPs

4.1.3 RCS Arrangement

4.1.3.1 Raised Loop - Davis-Besse, Bellefonte, WNP1

4.1.3.2 Lowered Loop - Everyone else

4.2 Construction Material

4.2.1 Materials must be compatible with environment of RCS.

4.2.1.1 Boric Acid solution

4.2.1.2 Temp of 650F - Pressure of 2195 psig

4.2.2 Materials

4.2.2.1 Stainless Steels - 316 and 304 alloys

4.2.2.2 Inconel - OTSG Tubes

4.3 Hot Leg Penetrations

4.3.1 Loop A - Decay Heat Removal

4.3.1.1 Functions to supply a suction to DHR pumps during:

a. Later portions of plant cooldown (305F, 400 psig)

b. Cold Shutdown operations

c. Refueling operations

4.3.1.2 DHR Return is into reactor vessel .

4.3.1.3 DHR Drop line penetration provides connection for lower tap of hot leg and vessel level transmitters

4.3.1.4 Upper taps

a. Reactor Vessel Vent

b. Top of Hot Leg

4.3.1.5 Level transmitters are installed to provide an indication of RCS inventory during accidents (Post TMI2 requirement). Also used during CSD if system is drained.

4.3.2 Loop A - Surge Line Connection

4.3.2.1 Purposes:

a. Allows the pressurizer to exert a pressure on the RCS

b. Allows for temperature induced volume changes to communicate with the pressurizer

4.3.2.2 RTD in surge line alerts the operator that spray line bypass flow in lost.

4.3.3 Loop A&B Flow Transmitters

4.3.3.1 Provide safety and non-safety indication

4.3.3.2 Safety Related- Flux/Delta Flux/Flow Trip

4.3.3.3 Non-Safety Related - ICS Feedwater Control and input to ULD for runback signal

4.3.3.4 Range 0 to 160 E6 lbs/hr

4.3.4 Loop A&B Temperature Detectors

4.3.4.1 Provide safety and non-safety indication

4.3.4.2 Safety Related

a. High Th Trip

b. Variable Low Pressure Trip

c. Saturation Monitor Input

d. SPDS Input

4.3.4.3 a&b above are narrow range - 530 to 650F

4.3.4.4 c&d are wide range - 50 to 650F

4.3.4.5 Non-Safety - ICS Feedwater Demand (Btu Alarm Calculation)

4.3.5 Loop A&B Pressure Indications

4.3.5.1 4 RPS Inputs

a. High Pressure Trip

b. Low Pressure Trip

c. Variable Low Pressure Trip

4.3.5.2 RPS Inputs are narrow range - 1500 to 2500 psig

4.3.5.3 ESFAS Pressure Input - wide range - 0 to 2500 psig - LOCA input.

4.3.5.4 SPDS Input - both ranges

4.3.5.5 Saturation Monitor input - wide ranges

4.3.6 High Point Vents

4.3.6.1 Purposes

a. Vents noncondensibles from RCS during accidents (Post TMI2)

b. Vents loops during startup

4.3.6.2 Remotely operated from control room

4.3.6.3 Post TMI2 requirement

4.3.7 Loop A&B Nitrogen connections

4.3.7.1 Used to inert the loops when the plant is in a drained condition.

4.3.7.2 Nitrogen excludes oxygen and corrosion is minimized.

4.4 Cold Leg Penetrations

4.4.1 Loop Drains - All Loops

4.4.1.1 Used to drain the RCS down for maintenance activities - e.g. RCP seal replacement

4.4.1.2 RCS is drained to Reactor Coolant Drain Tank

4.4.2 Letdown Line - RCP#2 Suction

4.4.2.1 Functions as a source of RCS fluid for the MU&P system

4.4.2.2 50 gpm is the normal letdown flow based on purifying one RCS volume in 24 hours.

4.4.3 Temperature Indications

4.4.3.1 Non -Safety Inputs

a. Derivation of Tavg

b. Derivation of delta T

c. ICS - FW demand delta Tc

d. Narrow range - 530 to 650F

4.4.3.2 Safety Inputs

a. SPDS

b. ATOG Display

4.4.4 Pressurizer Spray Connection - RCP#2 discharge

4.4.5 High Pressure Injection Connections

4.4.5.1 ECCS Supply to RCS

4.4.5.2 Makeup Line - RCP#2 Discharge

a. Return from MU&P system

b. Shares HPI nozzle to minimize penetrations.

4.4.5.3 Thermal sleeves installed on HPI nozzles

5.0 Pressurizer

5.1 Pressurizer Purposes

5.1.1 Maintains the RCS in a subcooled condition

5.1.2 Provides for RCS expansion and contraction

5.1.3 Provides overpressure protection for RCS

5.2 General Description

5.2.1 Vertical cylindrical tank with upper and lower hemispherical heads.

5.2.2 Total Volume = 2284 cubic feet

5.2.2.1 Steam Volume = 1184 cubic feet

5.2.2.1 Water Volume = 1100 cubic feet

5.2.3 Electrically heated - 1742kW of heaters

5.3 Spray Line Flow

5.3.1 Cold water from the discharge of RCP#2 is used to condense the steam bubble and lower pressure

5.3.2 Spray Line Details

5.3.2.1 Spray Line block valve - isolates a failed spray valve

5.3.2.2 Spray Valve - motor operated valve

a. Opens - 2245

b. Closes - 2195

c. Only opens 40% in automatic

d. May be fully opened in manual

e. Maximum Spray flow = 275 gpm

5.3.2.3 Spray bypass flow

a. Nominal value of 1 gpm

b. Prevents thermal shock of spray nozzle

c. Helps to equalize RCS and pzr boron

5.4 Pressurizer Safety and Relief Valves

5.4.1 Safety Valves

5.4.1.1 Prevent RCS pressure from exceeding 110%

5.4.1.2 Required by ASME -Section III

5.4.1.3 Lift at 2500 psig

5.4.1.4 Capacity = 500,000 lbm/hr per valve

5.4.1.5 Design Transient - 100% loss of load

a. No direct reactor trip

b. Rx trip on high RCS pressure

c. No control system actions

5.4.1.6 Discharge to RCDT

5.4.2 Power Operated Relief Valve

5.4.2.1 Electrically operated

5.4.2.2 Original purpose - to prevent a high pressure trip during normal transients

5.4.2.3 Present purpose - prevents lifting of safeties.

5.4.2.4 Setpoint = 2400 psig; cap = 1.5E5 lbm/hr

5.4.2.5 Block valve - vital powered - isolates failed PORV

5.4.2.6 Relieves to RCDT

5.4.3 Safety/PORV Indications

5.4.3.1 RTDs

5.4.3.2 Acoustical monitors - Post TMI2

5.5 Pressurizer Surge Line

5.5.1 Allows the pressurizer to communicate with the RCS

5.5.2 RCS penetration is thermal sleeved

5.5.3 Pressurizer contains a distribution baffle

5.5.4 RTD to indicate loss of bypass flow

5.6 Reactor Coolant Drain Tank

5.6.1 Receives Code Safety and PORV discharges

5.6.2 Receives loop drain effluent

5.6.3 Construction

5.6.3.1 Horizontal Cylinderical tank

5.6.3.2 Distribution headers on safety and relief inlets - allow steam to be discharged under water.

5.6.3.3 Rupture diaphram - 100 psig

5.7 Pressurizer Instrumentation

5.7.1 Pressure

5.7.1.1 Controls spray

5.7.1.2 Controls PORV

5.7.1.3 Controls heaters

5.7.1.4 Narrow range

~~5.7.1.5 Not installed on 177 FA units.~~

5.7.2 Level

5.7.2.1 Used to control position of MU valve

5.7.2.2 Temperature compensated

6.0 Theory of Pressurizer Operation

6.1 Assumptions

6.1.1 RCS is a closed hydraulic system

6.1.2 Water is 6 times more dense than steam

6.1.3 Pressurizer is a saturated system

6.1.4 Water is incompressible

6.1.5 Steam is ideal gas

6.2 Operations

6.2.1 Outsurges

6.2.1.1 Volume drops

6.2.1.2 Pressure decreases

6.2.1.3 Stored energy causes some flashing

6.2.1.4 Heaters add energy to boil water

6.2.1.5 Change is specific volume raises pressure

6.2.2 Insurges

6.2.2.1 Volume increases

6.2.2.2 Pressure increases

6.2.2.3 Increased pressure condenses some steam

6.2.2.4 Spray valve opens

6.2.2.5 Condensed steam's specific volume is less

6.2.2.6 Pressure decreases

7.0 Operations

7.1 Bubble Formation

7.1.1 Initial Conditions

7.1.1.1 RCS is filled and a 50 psig nitrogen bubble is present in the pressurizer

7.1.1.2 Explain that the nitrogen pressure is needed to keep hot legs full

7.1.2 Evolution

7.1.2.1 Energize heaters

7.1.2.2 When pressure increases to 60 psig, vent to RCDT

7.1.2.3 RCDT pressure will increase when N_2 is vented

7.1.2.4 Vent RCDT to waste gas system

7.1.2.5 Repeat 1 through 4 until RCDT pressure does not increase (Steam condenses)

7.2 Plant Heatup

7.2.1 Bubble in pzr

7.2.2 RCS pressure is increased above NPSH for RCPs

7.2.3 Three RCPs are started

7.2.4 Friction increases RCS temperature

7.3 Power Escalation

7.3.1 4th pump started at T>500F

7.3.2 Reactor taken critical

7.3.3 Turbine on line

7.3.4 Power is escalated with ICs

7.4 Chemistry Limits

7.4.1 Cover limits and bases

8.0 Review

8.1 Cover objectives

8.2 Answer student questions

3.0 Objectives

3.1 Cover the objectives listed on page 13.1

4.0 Presentation

NOTE - THIS PRESENTATION IS DESIGNED TO COVER THE 177 FA OTSG.

4.1 RCS Flowpath

4.2 Secondary Flowpath

4.2.1 Main Feedwater Nozzles
orfice plate to improve level stability

4.2.2 Aspirating Ports

4.2.3 Tube Contact - 15,531 tubes

4.2.4 Steam Outlets

4.2.5 Emergency Feedwater Flowpath

4.2.5.1 High nozzles

4.2.5.2 Sprayed directly on tubes for better natural circulation

4.3 Heat Transfer Regimes

4.3.1 Feedwater preheating accomplished by bleed steam from aspirating ports. Feedwater is at saturation by the time it reaches lower tube sheet.

4.3.2 Nucleate Boiling Region

4.3.2.1 Since the feedwater is at saturation, the latent heat of vaporazation is added.

4.3.2.2 Occurs as feedwater contacts tubes

4.3.2.3 region length is proportional to load (7 to 31 ft)

4.3.2.4 Avg. heat xfer coefficient = 6850 $\frac{\text{Btu}}{\text{hr-ft sq.}}$

4.3.2.5 Heat Flux = 50,000 Btu/hr-sq.ft.

4.3.3 Bulk (film) boiling region

4.3.3.1 Size almost constant with load (4 to 6 ft)

4.3.3.2 steam quality at outlet of region is 100%

4.3.3.3 Heat xfer coefficient = 1228

4.3.3.4 Heat Flux = 38,000 Btu/hr-sq.ft.

4.3.4 Superheat Region

4.3.4.1 remainder of tube length (41 to 15 ft) superheats steam.

4.3.4.2 35 degrees minimum

4.3.4.3 Heat transfer coefficient = 156

4.3.4.4 Heat Flux = 6000 Btu/ hr-sq.ft.

4.4 T AVERAGE CONTROL

4.4.1 Variable heat transfer area allows a constant T average above 15% power

4.4.2 As power approaches 0%, the level would approach 0 to maintain Tavg.

4.4.3 a minimum level is required for decay heat removal.

4.4.4 minimum level is called low level limits.

4.5 Level Indications

4.5.1 Low Range Level (startup level)

Measures downcomer level

4.5.1.1 Lower tap at the bottom tube sheet

4.5.1.2 Upper tap into tube bundle above aspirating ports.

4.5.1.3 total range is 250 inches

4.5.1.4 used by the ICS for low level limits control

4.5.2 Operating Range

Measures downcomer level

4.5.2.1 lower tap 96 inches above the lower tube sheet.

4.5.2.2 upper tap shared with the startup range.

4.5.2.3 scaled from 0 to 100%

4.5.2.4 ICS input for high level limits

4.5.3 Wide range level

4.5.3.1 lower tap is the same as the startup level

4.5.3.2 upper tap is at the upper tube sheet

4.5.3.3 0 to 600 inch range

4.5.3.4 Wet layup indication only

4.6 OTSG THERMAL STRESSES

4.6.1 Two areas of concern

4.6.1.1 Tube to shell

4.6.1.2 Tubesheet to shell

4.6.2 Tube to shell

4.6.2.1 tubes are inconel

4.6.2.2 shell is carbon steel

4.6.2.3 inconel expansion is sightly greater than carbon steel

4.6.2.4 In situations where the tubes are hotter than the shell, the OTSG is axially compression loaded.

4.6.2.5 Each of the tube supports act as a pinned point for the tubes.

4.6.2.6 Above situation is handled by insuring that the OTSG has a minimum feedwater temp and by pulling a vacuum on the OTSG during startups.

4.6.2.7 If a boiled dry situation persists, the tubes could become buckled.

4.6.2.8 In a steamline break, the tubes become colder than the shell, and a tensile stress situation exits.

4.6.2.9 Tubes may yield, but should not rupture

4.6.3 Tubesheet to shell

4.6.3.1 Critical weld area

4.6.3.2 potential for overstress if the feedwater is too cold.

4.6.3.3 Minimum feedwater temp limit

5.0 Technical Specifications

5.1 Applicable Technical Specifications

5.1.1 Spec 3.7.2 -Temperature/Pressure limits for OTSG

5.1.2 Spec 3.4.~~6~~ 5 - OTSG operability and surveillance

5.1.3 Spec 3.4.~~7~~ 6.2 - RCS leakage limits.

5.1.4 Spec 3.7.1.4 - OTSG Activity

5.2 OTSG Pressure/Temperature limits

5.2.1 OTSG secondary water temp shall be > 110 degrees when OTSG pressure > 237 PSIG ensures pressure induced stresses in the S/G's do not exceed the max allowable fracture toughness stress limits.

5.2.2 NDTT limit for the OTSG

5.2.3 STUDENT QUESTION - How do the utilities verify this limit?

5.3 OTSG Operability

5.3.1 Level Limit - ensures that level is within the values assumed in Safety Analysis.

5.3.2 Surveillance associated with the technical specification insures tube integrity.

5.4 B&W Tube problems

5.4.1 Majority of tube problems in the OTSG have occurred in or near the open inspection lane at the 15th tube support plate.

5.4.2 Open inspection lane was designed for visual inspection of the OTSG.

5.4.3 Vibration induced failures attributed to the high cross flow of steam in this area.

5.4.4 Intergranular stress corrosion is a possibility

5.4.4.1 Intergranular stress corrosion is the failure of a metal at the grain (crystal) boundaries "deep" within the metal.

5.4.4.2 Exact failure mechanism is not completely understood.

5.4.5 Maximum tube leakage has been approximately 12 GPM

5.5 OTSG Tube Leakage Limits

5.5.1 1.0 GPM total steam generator tube leakage

5.5.1.1 limit ensures that 10CFR100 limits will not be exceeded in the event of a steamline break or a steam generator tube rupture.

5.5.2 500 GPD through ~~both~~ either steam generators

5.5.2.1 500 GPD = .347 GPM

5.5.2.2 Bases - to insure tube integrity during a LOCA

5.5.3 STUDENT QUESTION - How is a leaking tube identified?

5.6 OTSG Surveillance requirements

5.6.1 Requirements in Standard Technical specifications are required by Reg Guide 1.83

5.6.1.1 1.83 defines methods that satisfy requirements of GDC 15 and 32

5.6.1.2 Requires the determination of the minimum steam generator tube thickness for a LOCA and design basis earthquake (site specific)

5.6.2 Tube Plugging Limits are specified in Reg Guide 1.121

5.6.2.1 Requires a determination of minimum steam generator tube thickness

5.6.2.2 Topical Report BAW-10146 submitted to NRC to meet the requirements of Reg Guide 1.121

5.6.2.3 Design tube thickness is .0375 inches

5.6.2.4 Minimum tube thickness by BAW - 10146 is .0116 inches. .0116/.0375 = 31% or a 69% thru wall degradation.

5.6.2.5 BAW - 10146 also recommends that any circumferentially cracked tubes be removed from service.

5.7 Tech Specification 4.4.6

5.7.1 Definitions

5.7.1.1 Degraded Tube - a tube containing imperfections greater than 20% (.0075 inch) of wall thickness caused by degradation.

5.7.1.2 Defective Tube - a tube that contains an imperfection greater than the plugging limit

5.7.1.3 Plugging Limit - an imperfection that is greater than 40%. .0225 inches vice the .0116 limit suggested by BAW - 10146. Conservative

Continued degradation + Eddy Current Testing Error

5.7.2 Inspections

5.7.2.1 100% of the tubes are required to be eddy-current tested prior to service to establish a base line for future inspections

5.7.2.2 If no preservice inspection was performed, both OTSGs must be inspected during the first inspection period.

5.7.2.3 One OTSG must be inspected during each subsequent inspection. 12 to 24 month inspection interval

5.7.2.4 Categories C1,C2,C3 are defined on 3/4 4-10

5.7.2.5 Cover worksheet